NARUC
National Association of Regulatory Utility Commissioners

NARUC Virtual Roundtable for Utility Regulators: Large Load Interconnection

March 9, 2026

Approximately 10 Commissioners participated in the members-only virtual roundtable on March 9, 2026, focused on large load interconnection processes and challenges. The discussion followed a presentation by Fritz Kahrl, of Lawrence Berkeley National Laboratory, on the technical and jurisdictional dimensions of large load interconnection. Participating states included Delaware, Idaho, Illinois, Minnesota, New Jersey, Texas, and Wisconsin. Topics included interconnection standards and study processes, cost allocation and jurisdictional ambiguities, flexibility services, resource adequacy implications, and the practical challenge of managing competing pressures from data center developers, ratepayers, and economic development interests. The summary below organizes the discussion thematically within nine topics.

1. Core Challenge: What Problem Are We Solving?

Commissioners emphasized that identifying the specific problem large load interconnection efforts are trying to solve varies significantly by jurisdiction and can shift even within a single state. **Wisconsin** focused on bridging the gap between transmission-level cost allocation (determined at the RTO level) and retail-level cost recovery under state jurisdiction, thereby obtaining transparency into how transmission costs flow through to retail rates. **Texas** identified two distinct challenges: determining which loads to include in forecasts and managing the interconnection study process itself. **New Jersey** highlighted that the underlying goal keeps shifting, and could be economic development, competitiveness, or pure ratepayer protection. This lack of clarity itself creates policy challenges.

Delaware emphasized the complexity of shared decision-making within an RTO footprint where one jurisdiction's actions affect all others through regional cost allocation. As a state importing all its energy, **Delaware** must solve for both energy access and transmission infrastructure while managing constantly shifting federal policies. **Idaho** described a largely reactive posture with utilities bringing proposals relatively late. The common thread across states was that defining the problem clearly before pursuing solutions remains surprisingly difficult given competing pressures from economic development interests, ratepayer advocates, and system reliability needs.

2. Interconnection Standards: Technical Requirements vs. Planning Standards

An important distinction emerged between technical standards (requirements customers must meet, like power factor or voltage ride-through) and planning standards (methods utilities use to study interconnection requests). Technical standards place compliance costs on the customer under a "participant pays" framework, avoiding socialization to all ratepayers. However, adoption of newer requirements has been piecemeal, and questions remain about what should be standardized, what should be mandatory, and what enforcement mechanisms exist.

One commissioner asked whether "interconnection standards" referred only to onsite requirements fully within customer control or also to planning standards that might trigger transmission upgrades with costs allocated elsewhere. The distinction matters to determine whether costs truly stay with the interconnecting customer. There are also questions about what's best managed through prescriptive standards versus what may better be handled through markets and operations. Setting requirements too rigidly may foreclose flexibility options that could be more efficiently managed through market mechanism, a balance described as potentially the most important design consideration in the entire interconnection framework.

3. Study Process: The Transparency and Consistency Gap

The interconnection study process (i.e., evaluating what infrastructure a facility needs and whether it will cause reliability issues) was identified as one of the biggest current gaps. In principle, studies should be based on NERC standards; in practice, some utilities have clear processes while others are opaque. The biggest upsides to standardization would be addressing lack of transparency in how utilities conduct studies and lack of consistency across utilities. However, standardization is more complicated for loads than for generation because load studies are done by many individual transmission owners rather than through a single federally regulated RTO process.

An additional complication is that some large loads do not know when they request interconnection whether they will connect at distribution or transmission voltage, suggesting the need for integrated processes rather than separate silos. When studies determine new transmission infrastructure is needed, that infrastructure should ideally be evaluated in regional transmission plans to avoid redundancy. **Wisconsin** and **Minnesota** highlighted the tension between fast-moving load interconnection and slow-moving regional planning, with **MISO's** processes becoming overloaded by trying to handle requests one at a time. Coordination remains important because load-triggered transmission is often local and lower-voltage, creating opportunities for system-beneficial upsizing.

4. Cost Allocation and Jurisdictional Ambiguity

Cost allocation emerged as both technically complex and jurisdictionally ambiguous. For transmission, FERC's "higher-of" policy theoretically allows charging the higher of incremental or average costs, but it's not always clear what transmission owners are actually charging or whether jurisdiction over these questions is within the purview of the federal or state commission. The distinction between interconnection agreements (covering interconnection requirements and costs) and electric service agreements (covering retail service) helps clarify boundaries but does not resolve all ambiguities.

Illinois referenced ComEd's filing of eight Transmission Service Agreements at FERC for large loads with mixed outcomes, illustrating the complexity of federal-level proceedings for state-jurisdictional customers. Recent agreements between hyperscale operators and the Administration, requiring data centers to pay for all costs including transmission upgrades and new generation, raise questions about feasibility and desirability. Where incremental costs exceed average costs, having data centers pay everything protects existing ratepayers. In other cases, bringing large loads into the retail umbrella to contribute to fixed costs may be more efficient. The answer likely varies by jurisdiction depending on system conditions and policy priorities.

5. Resource Adequacy and Interconnection

Resource adequacy planning is generally separate from interconnection, but the two intersect through load forecasting as utilities use queue information to populate demand projections. In most cases, loads can interconnect without having generation to back them up, which is why **Texas** requires curtailment priority for large loads and why **PJM** is developing similar approaches. If entry cannot be restricted at interconnection, consequences must be managed through operations. The only known exception is **SPP**, which can restrict entry based on resource adequacy.

One bridge between interconnection and resource adequacy is through "bring your own generation" initiatives that give expedited interconnection to loads supplying their own resources. Alternatively, customers could accept temporary or permanent curtailment services as part of interconnection, choosing operational restrictions in exchange for faster connection. This creates a framework where resource adequacy considerations shape interconnection terms without formally requiring generation backing as a precondition. **Minnesota** noted that both Google projects currently under review are bringing their own generation and battery storage, with the state also encouraging use of distribution-side batteries or virtual power plants, which is potentially a unique model for integrating distributed resources with large loads.

6. Load Flexibility: Principles, Practices, and Timing

Tools developed for generators, such as provisional interconnection service and non-firm transmission service, could in principle be applied to new large loads, with customers accepting curtailment in exchange for faster interconnection and potentially lower costs. **SPP's** Conditional High Impact Large Load Service and **PJM's** non-firm service for co-located arrangements represent emerging examples. The design principle should be focusing on how to provide options while maintaining reliability rather than starting from jurisdictional boundaries and working backwards. There are likely multiple creative pathways to achieve the same reliability outcome.

One commissioner asked whether data centers are becoming more flexible after initially insisting on uninterruptible service. The response: data centers are innovative with substantial capital and will do "just about anything" if incentives are right, likely incorporating more local generation and storage. However, another commissioner reframed the urgency question: Amazon will not fail if it does not get power immediately, but it will lose competitive position if Microsoft or Google gets capacity first. The urgency is about queue position relative to competitors, not absolute timing; they want to be first in line, not necessarily fastest in absolute terms. A critical insight from another commissioner: flexibility must be incorporated at the very beginning of planning to realize transmission system benefits. Once utilities have studied full load requirements and identified upgrades, offering flexibility later just shifts costs to other customers rather than avoiding them.

7. Speculative Load and Cascading Withdrawals

The challenge of speculative interconnection requests and cascading withdrawals when projects drop out after triggering shared infrastructure studies was discussed as analogous to long-standing generation interconnection problems. A new generator requests interconnection, studies identify expensive upgrades needed to support that interconnection, and the customer withdraws after being presented with those costs. Other customers in the queue who may have been counting on cost-sharing the needed upgrades must then be restudied. This situation triggers potentially cascading withdrawals as each learns their costs without the first customer.

This has been a 20-year problem without clean solutions. FERC Order 2023's "pay-to-play" approach for generators provides for significant financial commitments plus withdrawal penalties, which has helped but does not solve the problem entirely. For residual speculation, the response may be that it's simply part of having a competitive electricity system where developers shop for locations. One commissioner raised the parallel challenge of speculative generation, such as large amounts of offshore wind transmission that may be supporting generation that does not materialize, compounding study and cost allocation difficulties.

8. External Pressures: Economic Development and Political Dynamics

Multiple commissioners noted external pressures complicating technical decision-making. One commissioner observed that most governors view data centers as economically valuable, creating internal government pressure to facilitate development alongside commissioners' concerns about ratepayer impacts. **Texas** noted that economics is explicitly one of three statutory factors the Commission must consider, creating a balanced mandate beyond pure ratepayer protection.

Minnesota is facing pressure to shift environmental review authority from cities to the state PUC, which was included in state legislation under consideration this term (that did not pass). This is a different kind of external pressure about jurisdictional scope rather than project speed. **New Jersey's** governor called for a utility business model review with recommendations due in 120 days, potentially fundamentally reshaping interconnection, cost allocation, and planning. These examples illustrate how large load interconnection is increasingly shaped by political and economic development considerations that operate outside traditional utility regulatory frameworks.

9. State-Level Variations and Approaches

States reflected diverse approaches based on regulatory structures and development stages. **MISO** states (**Wisconsin, Illinois, Minnesota**) share challenges coordinating state retail jurisdiction with regional transmission planning and cost allocation. In **Illinois**, legislation creating a data center framework with bring-your-own-generation incentives and flexible interconnection benefits was introduced in 2024, but it failed to pass and will be surfaced again. **Minnesota** has 2025 legislation requiring IOUs to file data center tariffs by December 2026 and raised concerns about **MISO's** expedited review process where utilities can reclassify projects from interconnection cases to reliability projects, shifting costs from the specific load to all customers.

PJM states (**New Jersey, Delaware**) face the complexity of 13 jurisdictions sharing decision making where one state's actions affect all others through regional cost allocation. **New Jersey** is reviewing its entire utility business model with recommendations due in 120 days. **Delaware** imposed a moratorium on loads over 25 MW while awaiting tariff proposals; as a state importing all of its energy, it faces particular challenges ensuring adequate resources and transmission.

Non-RTO states face different dynamics. **Texas** operates ERCOT and manages queue challenges without layered RTO jurisdiction. **Idaho** utilities have been bringing projects late in development, so the Commission has a reactive approach. The variety reflects not just different regulatory structures but different stages of grappling with data center growth and its implications.